BRIEFING - September 2025

Blue threat: can EU hydrogen policy stay green?

Assessing the new Low-Carbon Fuels Delegated Act and the case for prioritising RFNBO hydrogen

Summary

Following the recent adoption of the Delegated Act (DA) on low-carbon fuels, the EU has completed the regulatory framework for both renewable (RFNBO) and low-carbon hydrogen production. The worst case scenario has been avoided. The default emissions value for natural gas excludes key segments such as Liquified Natural Gas (LNG) liquefaction, shipping and regasification, that must be calculated separately. Yet the prescribed emissions values still downplay the real climate impact of blue hydrogen production and their effectiveness will hinge on a strong and enforceable Methane Regulation in the future.

Additionally, shortcomings with the rules will undermine the climate integrity of low-carbon hydrogen. The proposed rules rely on outdated methane leakage rates and fail to consider the short-term climate impacts of methane, and leave critical gaps in midstream emissions accounting. Low-carbon electrolysis hydrogen also benefits from looser rules compared to RFNBO hydrogen, creating an uneven playing field. There is a real risk of locking in high-emission hydrogen pathways under the guise of 'low-carbon'.

To that end, T&E recommends the EU to:

1. **Ensure strong safeguards for calculating low-carbon hydrogen emissions**: Ensure full lifecycle GHG accounting of natural gas, including an assessment of upstream methane leakage and midstream emissions as well as considering the higher short-term climate impacts of methane.
2. **Maintain regulatory stability** : Do not reopen and weaken the GHG methodology for RFNBO rules. With both RFNBO and low-carbon hydrogen methodologies now defined, investors need regulatory stability to move projects to Final Investment Decisions.
3. **Focus on supporting first-of-a-kind projects:** Keep the focus on enabling Final Investment Decisions for RFNBO projects, and support long-term offtake agreements for airlines and shipping companies to ensure e-fuels can meet FuelEU and ReFuel targets, through financial mechanisms such as European Hydrogen Clearing House.

1. From the high to the how: a shift in hydrogen policy

Today, 96% of hydrogen produced in the EU is fossil based and only a small number of renewable hydrogen projects have reached Final Investment Decisions. Targets alone are not enough. The EU needs a clear plan for where and what type of hydrogen will be used, how infrastructure will be rolled out and where and how public support will be targeted.

The EU's REPowerEU objective of 20 million tonnes of hydrogen by 2030 has not yet materialised into real-world deployment. Promoted across too many sectors without strategic focus, hydrogen was often advocated for where cheaper and more efficient electrification options exist. This has led to fragmented policies and wasted resources. More recently, a comprehensive regulatory framework for renewable hydrogen deployment has emerged, with definitions and targets that go some way in addressing the previous lack of focus. These include; the Hydrogen and Gas Market Package, the revised Renewable Energy Directive (RED) III, and the new ReFuelEU and FuelEU. However, shortcomings remain.

The recent adoption in July 2025 of the Low-Carbon Fuels Delegated Act (DA) marks a landmark decision. It brings regulatory clarity on how to produce low-carbon hydrogen. With both the RFNBO and low-carbon hydrogen frameworks now in place, **regulatory certainty is welcome.** But concerns remain around the practical implementation of the latter.

If the EU is serious about scaling up hydrogen to decarbonise hard-to-abate sectors, where direct electrification is not feasible, it must ensure robust definitions and that clean hydrogen is not undermined by fossil fuel loopholes. Without strong safeguards, the new rules on low-carbon hydrogen could allow fossil-based hydrogen to compete for public money and infrastructure. This risks locking in fossil gas and slowing down the scale-up of truly clean hydrogen.

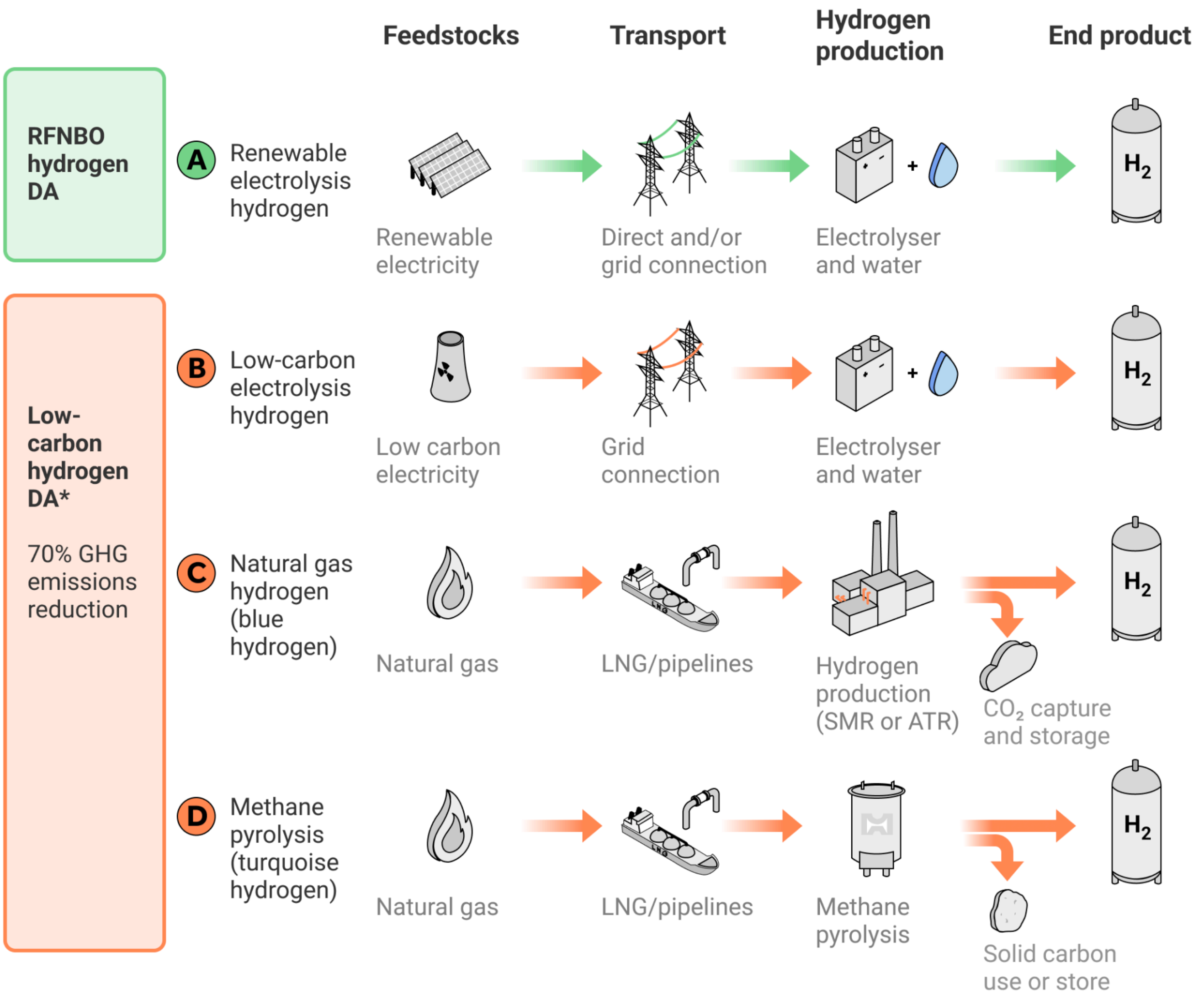
2. What is meant by low-carbon hydrogen?

The Hydrogen and Gas Market Directive (EU) 2024/1788 introduced a broad definition of low-carbon hydrogen: *hydrogen derived from non-renewable sources that achieves at least 70% greenhouse gas (GHG) savings compared to a fossil comparator.* With a fossil comparator set at 94 gCO_{2e}/MJ of hydrogen, the emissions reduction threshold equates to 28.2 gCO_{2e}/MJ of fuels as delivered to the final consumer. The newly published DA sets out the methodology for calculating emissions, in a similar way to the GHG methodology for RFNBO (Commission Delegated Regulation (EU) 2023/1185 of 10 February 2023). But unlike RFNBOs hydrogen which must be produced via electrolysis with additional renewable electricity, low-carbon hydrogen can originate from a wide variety of technologies as shown by the diagram below.

These technologies include fossil-based processes like Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) combined with carbon capture and storage (CCS), electrolysis powered by non-renewable low-carbon electricity, methane pyrolysis, or hydrogen recovered as a by-product of industrial processes (e.g., chlor-alkali production).

Today, the "low-carbon" hydrogen most often referred to is fossil-based hydrogen equipped with CCS, commonly known as **blue hydrogen**. This route could in theory decarbonise existing fossil fuels-based hydrogen production, but the empirical performance of CCS remains uncertain. Another significant pathway is **low-carbon electrolytic hydrogen** produced from all electricity sources, except renewables covered by the RFNBO rules, that meet the 70% reduction threshold. A less established pathway is hydrogen produced from **methane pyrolysis** technology, splitting natural gas into hydrogen and solid carbon at very high temperature.

The EU has now defined the different hydrogen pathways - but not all of them should be prioritised equally



Source: T&E. LNG: Liquified Natural Gas; DA: Delegated Act; GHG: greenhouse gases; SMR: Steam Methane Reforming; ATR: Authotermal reforming. *Pathways B, C, D represent the main technologies under the Low-Carbon hydrogen Delegated Act

3. The Low-Carbon Fuels Delegated Act avoids the worst case, but still falls short

In the Low-Carbon Fuels DA, the lifecycle GHG emissions from the production of blue hydrogen requires inclusion of both upstream and midstream emissions from the fossil gas feedstock. This means emissions from extraction, processing, and transport must be accounted for.

- **When fossil gas is part of an incorporated process**[1]: companies must use actual production data covering the full supply chain.
- **When fossil gas is not directly part of an incorporated process**: default values from the DA can be used (listed in Part B, Table 1 of the Annex).

For EU-produced gas, methane emissions must be reported by producers under the Methane Regulation (Commission Regulation (EU) 2024/1787). For imported gas, including LNG, reporting obligations will apply to importers from 2027 onwards. Methane emissions linked to the transport of fossil gas will also need to be reported, based on the EU Methane Transparency Database expected in 2027. But importantly, in the interim, where verified methane data are not available, operators must rely on default methane intensity values found in Part B, Table 1 of the DA Annex.

Table 1: Natural gas default lifecycle GHG emissions value

Feedstock	CO_2	CH_4	N_2O	Total default value
Natural gas	4.9 gCO_{2e}/MJ	5.32 gCO_{2e}/MJ*	0.098 gCO_{2e}/MJ	**10.32 gCO_{2e}/MJ**

* According to Table 1, Part B of the Annex to the DA, a default CH_4 emission intensity value of 0.19 is provided, which must be multiplied by the GWP100 factor of 28, according to Delegated Regulation (EU) 2020/1044.
** Excluding Liquefied Natural Gas liquefaction, shipping and regasification emissions.

3.1. The methane emissions default value underestimates blue hydrogen climate impact

Fossil gas has long been promoted as a so-called ‘transition fuel’, a stepping stone towards a more renewables-based energy system. In debates about the merits of green hydrogen, blue hydrogen produced from fossil gas has been described as cheaper, quicker to scale while delivering a similar level of emissions reductions. However, this rosy picture on blue hydrogen very much depends on how the climate impacts of methane are assessed. There are two key reasons why the DA underestimates the negative climate impact of blue hydrogen.

[1] Incorporated processes include processes that 1) take place in the same industrial complex, and 2) reuse heat or other hard-to-transport outputs of one of the processes.

Firstly, the default value of 5.32 gCO_{2e}/MJ assumes fossil gas to have a **methane leakage rate** of around 1.2% (cf methodology). This is significantly lower than the global average leakage rate, estimated to be between 2.8 - 3.2% (cf methodology). For gas-producing countries with weaker methane mitigation policies, such as the United States, Algeria or Nigeria, leakage rates can exceed 5 - 6%, making the DA's default far off with real-world data.

Secondly, methane is a Short Lived Climate Forcer (SLCF), which remains in the atmosphere for a shorter period, but its potential to warm the atmosphere can be many times greater than CO_2. Hence, the selected timeframe has a decisive impact when assessing whether blue hydrogen reduces emissions. The Commission's decision to continue applying a 100-year Global Warming Potential (GWP 100) value of 28 to upstream fugitive methane emissions, as set out in Delegated Regulation (EU) 2020/1044, is problematic. Over a 20-year period, methane's GWP is estimated at 84–87 (GWP 20) as reported in the Report Intergovernmental Panel on Climate Change, highlighting its significant near-term effect on climate change. Using the GWP 20 in the context of the Low-Carbon Fuels DA would help ensure that blue hydrogen producers are required to only source fossil gas with very low upstream methane emissions. In other contexts, the GWP 100 remains relevant to also assess the longer-term impacts of methane and other greenhouse gases (e.g. when assessing Nationally Determined Contributions (NDCs) under the UNFCCC).

3.2. The failure to provide a transparent methodology could result in incomplete accounting

The absence of a clear and transparent methodology for calculating midstream emissions risks leading to incomplete or inconsistent accounting by blue hydrogen producers. Indeed, the revised default GHG intensity for natural gas, 10.32 gCO_{2e} /MJ, includes the midstream emissions of pipeline gas. However, the emissions associated with the liquefaction, shipping and regasification of Liquified Natural Gas (LNG) are excluded and must be calculated separately.

For the calculation of methane emissions from LNG, the DA refers to the forthcoming Methane Intensity Methodology Delegated Act. However, the Methane Regulation (EU) 2024/1787 only requires this DA to be published by August 2027. In the meantime, LNG importers are left without a robust basis for calculating midstream emissions. The Low-Carbon Fuels DA references different reports but without further transparency, creating the risk of data cherry-picking. Worse still for other greenhouse gases such as CO_2 and N_2O linked to the transport of fossil gas, no methodology is foreseen, compounding the problem of incomplete lifecycle accounting.

3.3. Delegated Act makes blue hydrogen not impossible but it will require 'best in class' projects

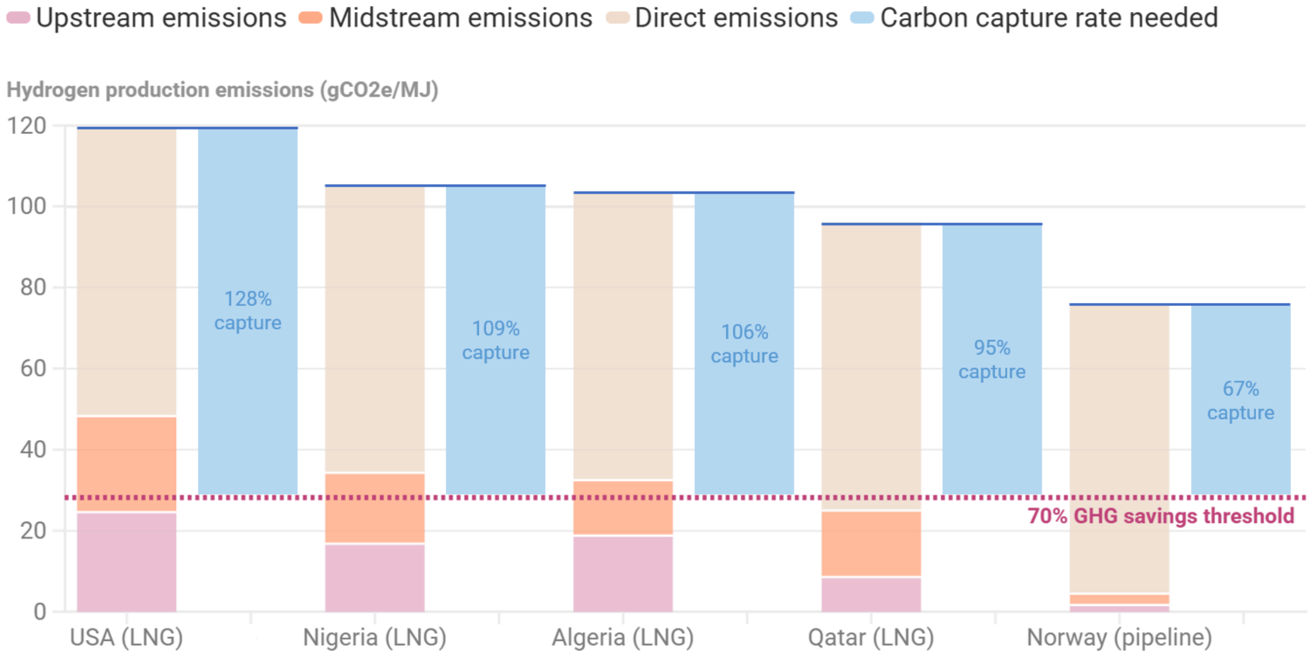
While the DA does not make it impossible for blue hydrogen to meet the 70% GHG reduction threshold, this will only be achievable by those projects, which can minimise their emissions. To qualify, producers will need to procure fossil gas with extremely low methane leakage and apply carbon capture rates at the very top end of what has been achieved so far. Projects relying on LNG will struggle even more, as the extra emissions from liquefaction and shipping are not factored in the default value and must be added separately in the lifecycle emissions.

To qualify as low-carbon, hydrogen from fossil gas must emit less than 28.2 gCO_{2e}/MJ across its lifecycle when delivered to the final consumer - equivalent to a 70% reduction from the fossil comparator of 94 gCO_{2e}/MJ of hydrogen. This is only achievable with very high CO_2 capture rates and low upstream emissions. To achieve the high CCS capture rates needed, more innovative technologies may need to be used, which will increase costs. Therefore, CCS technologies can fall short in capturing more than 60-70% of process emissions in a cost-effective way.

The carbon intensity of hydrogen production rises sharply when fossil gas is sourced via LNG. A study commissioned by T&E found that the average upstream emissions of EU LNG imports stand at 24.4 gCO_{2e}/MJ of natural gas. Hence, it assumes that, due to energy-intensive liquefaction and transport, LNG emissions can add around 14 gCO_{2e}/MJ on top of the 10.32 gCO_{2e}/MJ EU's default value for natural gas. More than doubling its upstream footprint.

As shown in the graph below, US LNG natural gas supply chains emit on average around 48.5 gCO_{2e}/MJ of hydrogen produced when both upstream and midstream emissions are accounted for. Adding 71.1 gCO_{2e}/MJ of hydrogen for direct emissions from the SMR process, from both natural gas combustion and reforming, pushes total blue hydrogen emissions far beyond the 28.2 gCO_{2e}/MJ threshold. Our analysis shows that under these conditions, a CCS-equipped hydrogen plant would need to capture close to 130% of process emissions - a technical impossibility. More on our approach in the methodology section.

Hydrogen produced from imported gas will require high carbon capture rates to comply with EU low carbon rules, except for "least dirty" gas.



Source: T&E analysis, based on SMR efficiencies from Howarth (2021), LNG upstream and midstream emissions averaged from IFEU (2023) and EERA (2024) • Carbon capture rate expressed as share of direct emissions needed to comply with 70% GHG savings. Direct emissions include both emissions from natural gas combustion and reforming.

That said, under best-case conditions, compliance is possible. For instance, importing low-emission pipeline gas from Norway and using a classic SMR process, the required CO_2 capture rate drops to around 67%. This is technically achievable but at the upper end of what most CCS projects have delivered in practice until now.

3.4. Biofuels loophole risks greenwashing high-emission hydrogen sourced from natural gas

The DA allows biofuels, bioliquids or biomass fuels to be used as *non-relevant energy input* in hydrogen production. In practice, this means that while fossil gas remains the feedstock for blue hydrogen SMR/ATR processes, the additional fossil gas burned to generate the heat and steam needed for reforming can now be substituted with biofuels. This does not change the fossil nature of the hydrogen as an end-product but can lower the carbon intensity.

In conventional SMR, process fuel typically represents a significant share of total gas consumption (often around 40%, depending on the configuration). This provision can represent potentially a dangerous loophole, as advanced bioenergy feedstocks (using wastes & residues) are limited and already in high demand across EU sectors. According to a T&E study, Europe's existing biofuel policy mandates already exceed the availability of sustainable biofuels. The loophole also risks driving greater use of crop-based biofuels, as RED III ignores indirect land-use change (ILUC) impacts and the revision of the Delegated Act establishing high ILUC risk feedstocks, keeps being postponed. Diverting bioenergy resources to "greenwash" fossil hydrogen, especially when the gas feedstock comes from high-emission sources like US LNG or Algerian gas, can have associated risks. It can lead to indirect emissions, potentially cancelling any savings compared to fossil fuels.

4. Looser rules risk putting RFNBO hydrogen at a disadvantage

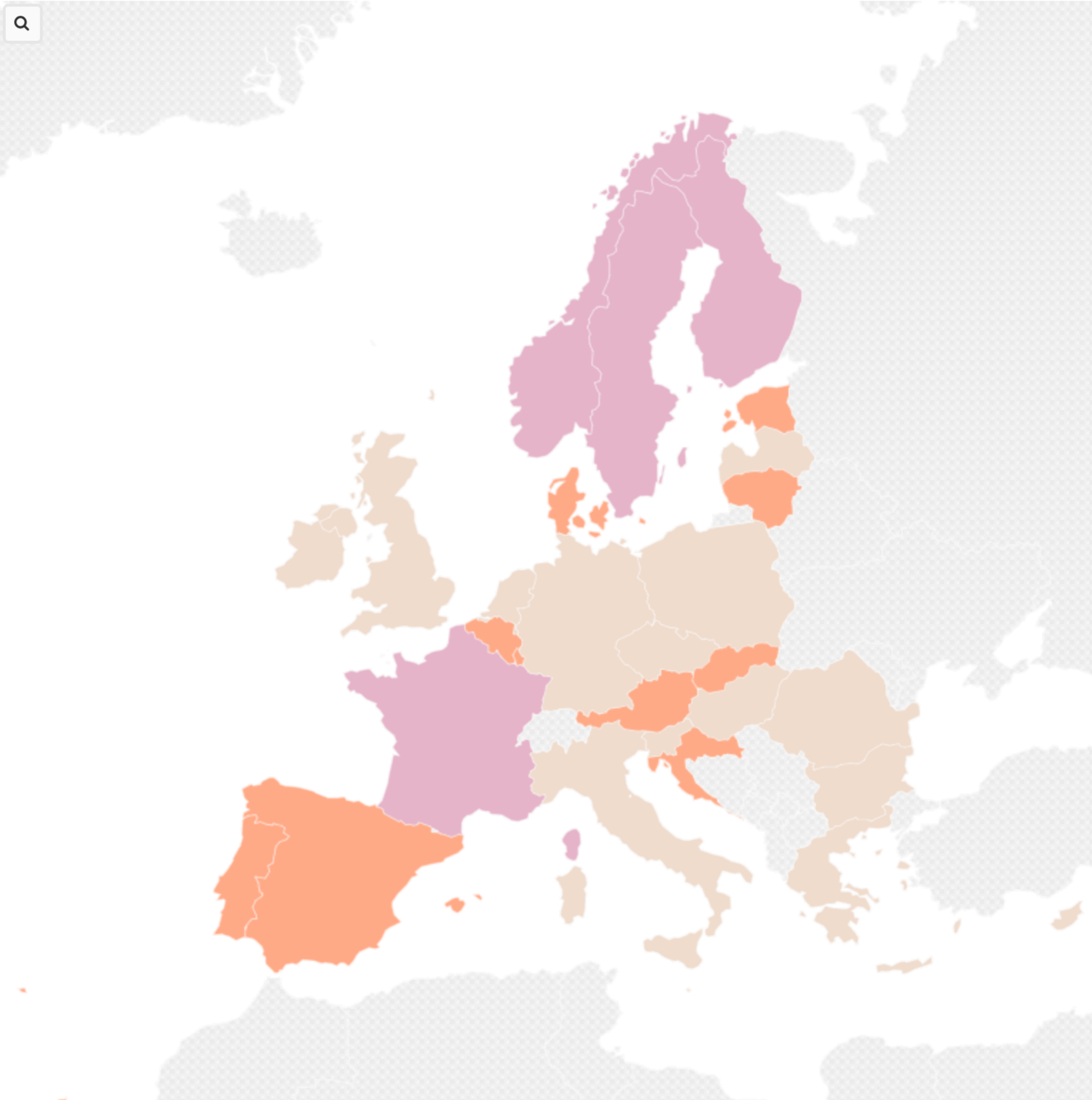
As mentioned earlier, the new DA covers low-carbon electrolytic hydrogen using grid electricity, as long as it meets the 28.2 gCO_2e/MJ threshold. However, it does not include the same safeguards as the RFNBO rules to ensure real climate benefits. This means projects using low-carbon electricity could qualify for support without meeting the stricter RFNBO requirements, potentially putting renewable electrolytic hydrogen producers at a disadvantage. In particular, there is:

- **No additional incentives for system-wide grid decarbonisation**: The EU's RFNBO rules set a high bar for what qualifies as renewable hydrogen. Strict requirements on additionality, temporal and geographic correlation for sourcing renewable electricity via the grid ensure that renewable hydrogen delivers emissions reductions and drives new renewables deployment. Unlike RFNBOs, low-carbon hydrogen producers are not required to demonstrate that their electricity use comes with similar climate safeguards. As long as they meet the threshold, they can rely on a mix of existing grid renewables, nuclear or even fossil-based electricity. Indeed, the DA ensures that the final hydrogen delivered meets the carbon intensity required but it does not create the same structural obligations as RFNBO rules to accelerate system decarbonisation.

- **Room for discretion in applying hourly accounting temporal correlation**: Hourly average grid GHG intensity is listed as two of four possible methods to calculate emissions from the grid. For the production of RFNBOs, producers must apply hourly matching between renewable production and their electricity consumption from 2030. But in practice, challenges remain from the implementation of hourly accounting at scale. Consequently, producers are likely to choose laxer methods, relying on reported yearly averages of the carbon intensity in the member state where their project is located. For instance, the DA could have required a progressive tightening of the four available grid emissions accounting methods, phasing out annual or national-average approaches and converging on hourly matching by 2030. This would have ensured that all producers were subject to the same standard as RFNBO hydrogen, thereby creating a level playing field.

Only half of European countries are expected to meet the low-carbon grid intensity threshold by 2030

Has low-carbon grid · Expected to have low carbon grid by 2030 · No low-carbon grid



Source: T&E (2025), based on Ember (2025) for CI values and Hydrogen Europe for 2030 projections

5. No backsliding with RFNBOs hydrogen

Adopted in 2023, the RFNBO DAs set out strong safeguards to ensure that renewable electrolytic hydrogen contributes to emissions reduction, enables the deployment of renewable electricity in Europe and prevents diverting renewables for hydrogen production, which could have displaced fossil power generation on the grid. These rules try to strike a balance between safeguarding the environmental integrity of RFNBO rules and supporting the scale up of a nascent hydrogen industry.

Debunking some of RFNBO rules criticisms:

- **Additionality requirement - no inclusion of the grandfathering clause:** Under the current rules, electrolysers that become operational from January 2028 must comply with additionality requirement. This requires the signing of a power purchase agreement with a renewable energy generation asset commissioned no later than 36 months before the start of the electrolyser operation. Electrolysers installed before January 2028 are subject to a transition phase until 2038, during which they are exempt from this requirement. There is a risk that pushing this deadline further into the future or permanently exempting pre-January 2028 electrolysers from additionality via a grandfathering clause creates two regulatory regimes and distorts a level playing field between different projects. This will also create unnecessary complexity in certification and undermine regulatory consistency.

- **Hourly matching is workable with today's electrolyser technology but it comes with operational considerations**: Both alkaline and PEM electrolysers demonstrate start-up dynamics that are compatible with the hourly matching temporal correlation requirement. Alkaline electrolysers typically require 5-15 minutes for a cold start and 1-5 minutes for a warm start, while PEM electrolysers are even more agile, with cold starts in 10-15 minutes and warm starts in under one minute.

  These response times are sufficient to meet hourly variations in renewable electricity supply and can support better alignment of hydrogen production with renewable availability. Also, hourly matching promotes demand-side flexibility and system integration, making better use of surplus renewable electricity during periods of curtailment or negative spot prices, while also stabilising the market value of renewables. This reduces curtailment. However, it is difficult to exclude the risk that if not managed properly, frequent start-stop cycles can accelerate electrolyser stack degradation and reduce overall efficiency. The lack of experience in operating electrolysers flexibility for long periods means significant uncertainty remains in this area.

- **CAPEX-related cost differentials due to hourly matching are overstated**: the cost of hydrogen depends on the cost of renewable electricity and the cost of the electrolyser (CAPEX). There is concern that the extra cost of complying with the temporal correlation requirement can be overstated by industry stakeholders. On average, CAPEX represents around half of the current cost of renewable hydrogen. However, the electrolyser price share is likely to decrease as their performance is expected to improve with technological advancements and through the production scale-up leading to economics of scale. In practice, this means the upfront cost increase tied to hourly matching is likely to shrink over time and not to increase, predominantly dependent on electricity prices.

Moreover, ensuring hourly matching leads to additional GHG savings. In most European grids the marginal generator during periods of low renewable availability is still fossil fuel generators. Hourly matching ensures that the hydrogen production does not consume grid electricity in fossil-heavy hours. Instead, it ties hydrogen production to actual renewable generation.

5. Recommendations

With the adoption of both DA, the EU has now delivered the long-awaited **regulatory certainty** needed to attract investment and bring projects to **Final Investment Decision**. This clarity must not be undermined. The focus should now shift from rule-making to effective implementation, ensuring that the framework delivers on its objectives and gives investors the confidence to move projects forward.

To that end, T&E recommends the EU to:

1. **Ensure strong safeguards for calculating low-carbon hydrogen emissions**: Ensure full lifecycle GHG accounting of natural gas, including an assessment of upstream methane leakage and midstream emissions as well as considering the higher short-term climate impacts of methane.
2. **Maintain regulatory stability**: Do not reopen and weaken the GHG methodology for RFNBO rules. With both RFNBO and low-carbon hydrogen methodologies now defined, investors need regulatory stability to move projects to Final Investment Decisions.
3. **Focus on supporting first-of-a-kind projects:** Keep the focus on enabling Final Investment Decisions for RFNBO projects, and support long-term offtake agreements for airlines and shipping companies to ensure e-fuels can meet FuelEU and ReFuel targets, through financial mechanisms such as European Hydrogen Clearing House.

Table 2: Comparative table of hydrogen regulation in the EU, the UK, and China

	EU		UK	China		
Type of hydrogen	**RFNBO hydrogen**	**Low-carbon hydrogen**	**Low-carbon hydrogen**	**Renewable hydrogen**	**Low-carbon hydrogen**	**Clean hydrogen**
Regulatory document	Commission Delegated Regulation (EU) 2023/1185 on Renewable Fuels of Non-Biological Origin	Commission Delegated Regulation (EU) 2024/1788 on low-carbon hydrogen	UK Low Carbon Hydrogen Standard	(Draft) 2025 Clean and Low-carbon Hydrogen Evaluation Standard	(Draft) 2025 Clean and Low-carbon Hydrogen Evaluation Standard	(Draft) 2025 Clean and Low-carbon Hydrogen Evaluation Standard
Definitions and standards	1) lifecycle emissions ≤28.2 gCO_2e/MJ, incl. transport 2) meets the a) additionality requirement b) temporal and geographical correlation rules.	1) lifecycle emissions ≤28.2 gCO_2e/MJ, incl. transport Covers grid electrolytic hydrogen and CCUS-based hydrogen	1) lifecycle emissions ≤20 gCO_2e/MJ, incl. transport 2) additionality requirement Covers electrolytic hydrogen (from grid/renewables) and CCUS-based hydrogen	1) renewable energy only and 2) lifecycle emissions ≤16.7 gCO_2e/MJ, excl. transport	1) lifecycle emissions ≤110.3 gCO_2e/MJ.	1) lifecycle emissions ≤32.17 gCO_2e/MJ, excl. transport

Sources: Low-Carbon Fuels Delegated Act, RFNBO Delegated Act, ICIS 2025, UK low carbon hydrogen standard

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Further information

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Methodology

Default methane leaking rate estimate

Upstream methane leakage associated with the default value provided in the new EU rules have been estimated using the following formula:

$$Methane\ leakage\ rate\ (\%) = \frac{E_{CH4} * HHV_{NG}}{f_{CH4} * GWP_{CH4}}$$

Where:

E_{CH4} are the equivalent upstream methane emissions per unit of natural gas delivered (gCO_{2e}/MJ)

HHV_{NG} is the higher heating value of natural gas (MJ/kg)

f_{CH4} is the typical mass fraction of methane in natural gas

GWP_{CH4} is the global warming potential of methane (gCO_{2e}/gCH_4)

Using an HHV of 53.5 MJ/kg (IPCC), a GWP of 28 $gCO_2e/g\ CH_4$ (EC. 2020/1044), and assuming 85% methane by mass in natural gas, the 5.32 gCO_2e/MJ upstream and midstream emissions in the Low-Carbon Delegated Act translate into a methane leakage rate of ~1.2%.

Global average methane leaking rate estimate

Global upstream methane leakage is estimated around 80 $MtCH_4$ in 2024 according to the IEA's Methane Tracker, which accounts for total emissions from gas production and transport infrastructure, including satellite-detected releases. Benchmarking these emissions against global natural gas output of ~4,200 bcm indicates that methane leakage represents approximately 2.8–3.2% of production, depending on methane content in natural gas. Such a global average range can also be found in reviews of different studies.

Carbon capture rates needed to comply with EU rules

Steam Methane Reforming (SMR) relies on natural gas both as feedstock and fuel. On average, producing 1 MJ of hydrogen requires about 1.3 MJ of natural gas. The reforming reaction itself emits 38.5 gCO_2 per MJ of hydrogen, while we estimate that the combustion of natural gas as fuel adds another ~32.6 gCO_2, based on the Low Carbon Delegated Act factor of 56.2 gCO_2/MJ for natural gas. Altogether, SMR hydrogen production thus results in an emission intensity of roughly 71 gCO_2 per MJ of hydrogen.

Considering emissions from both the SMR process (combustion and reforming) and the natural gas supply chain (upstream and midstream), we then estimated the carbon capture rate needed to achieve the EU's 70% greenhouse gas savings threshold with the following approach.

$$e_{SMR} = e_{reforming} + e_{combustion}$$

$$e_{upstream/midstream} = NG_{use} * (e_{upstream} + e_{midstream})$$

$$CCR = \frac{e_{SMR} + e_{upstream/midstream} - (1 - GHG_{threshold})^* e_{fossil}}{e_{SMR}}$$

Where:

e_{SMR} is the total emissions from a conventional SMR process (gCO_{2e}/MJ_{H2})

$e_{reforming}$ is the emissions from the reforming of natural gas (gCO_{2e}/MJ_{H2})

$e_{combustion}$ is the emissions from the combustion of natural gas (gCO_{2e}/MJ_{H2})

NG_{use} is the total quantity of natural gas used both for the reforming reaction and the energy input of the SMR process (MJ_{CH4}/MJ_{H2})

$e_{upstream}$ and $e_{midstream}$ are the upstream and midstream emissions from the natural gas supply chains (gCO_{2e}/MJ_{CH4})

$GHG_{threshold}$ is the minimum emissions savings required to comply with EU low carbon rules (70%) compared to fossil fuels

e_{fossil} is the fossil fuel comparator emissions (94.2 gCO_{2e}/MJ)

CCR is the carbon capture rate required to meet the EU emissions savings threshold (%)

Our analysis indicates that using the default values from the Low Carbon Delegated Act, a typical SMR process would require a carbon capture rate of around 80%. When incorporating actual upstream and midstream emissions reported in studies such as those by EERA and IFEU, we find that natural gas from major LNG suppliers to the EU would require even higher capture rates to meet EU thresholds. Alternatively, electrifying the heat supply for SMR, especially using low-carbon electricity, could reduce overall emissions and help meet the targets with lower capture requirements. Our approach does not take into account the energy requirements from the carbon capture technology itself, thus ignoring the associated emissions.